FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

IDAHO POWER COMPANY

Docket Number: ID-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

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I. FILING DATA

Utility	Parties to the Filing
Idaho Power Company P.O. Box 70 (83707) Boise, ID 83702	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
Production Cost	$398,773,303	$398,771,211	$398,771,211	$399,101,933
Transmission Cost	$94,625,570	$94,642,415	$94,642,415	$94,642,415
(Less) New Large Single Load Costs	$0	$18,084,845	$26,461,649	$26,461,649
Total Contract System Cost	$493,398,873	$475,328,781	$466,951,978	$467,282,700
Total Retail Load (MWh)	13,939,314	13,939,314	13,939,314	13,939,314
(Less) New Large Single Load	0	385,440	385,440	385,440
Total Retail Load (Net NLSL)	13,939,314	13,553,874	13,553,874	13,553,874
Plus Distribution Losses	696,966	1,084,713	1,084,713	1,084,713
Total Contract System Load (MWh)	14,636,280	14,638,587	14,638,587	14,638,587
FY 2006 Base Period ASC ($/MWh)	**33.71**	**32.47**	**31.90**	**31.92**

B. FY 2009 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**33.68**	**33.53**	**33.86**

C. FY 2009 (Exchange Period) ASC with New Resource Additions ($/MWh)

Idaho Power provided BPA new resource information on May 9, 2008. BPA has confirmed with Idaho Power that the new resource is now on line. Cost and load information for this resource is shown in Table1 in Section III.B and such information is included in Table 2, Section V., final Expedited ASC Forecast for FY 2009-2013.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. See 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging utilities agreed to a number of termination agreements that provided for payments to each utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. <u>ASC Determination Process Guidelines and Expedited Review Process</u>

The purpose of BPA's expedited review process is to estimate exchanging Utilities' ASCs for FY 2009 for inclusion in BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding rely on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities, which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance with the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1. The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a base period ASC determination, BPA used the ASC Forecast model, an Excel-based spreadsheet, to escalate the base year ASC forward to the effective rate period, FY 2009 (October 1, 2008, through September 30, 2009). The base year and forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capitol (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and administrative and general expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1, in order to determine the Utility's return on investment.

Investor Owned Utilities (IOUs) use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For Consumer Owned Utilities (COUs), the rate of return is equal to the COU's weighted cost of debt.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as described above. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items.

<u>Contract System Cost</u>
The Contract System Cost is the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve a new large single load (NLSL) are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

<u>Contract System Load</u>
The Contract System Load is the total regional retail load included in the Form 1, or for a COU (preference customer) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any NLSL.

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Sales for Resale

Purchased Power is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1 pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A new large single load (NLSL) is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10 aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of <u>all</u> post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro-rata basis using salary and wage data for production, transmission, and distribution/other functions included in the Utility's most recently filed FERC Form 1. For COUs, comparable data is used based on a cost of service study used as the basis for retail rates at the time of review.

D. <u>ASC Forecast</u>

The 2006 Base Period ASC is applied to an Excel-based forecasting model to escalate the base year ASC data forward to the Exchange Period. For purposes of this expedited process, the Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its Priority Firm (PF) Power Rate and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Cost

Forecast Contract System Cost (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with an Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5 percent change to ASC. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of any major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. <u>Identification and Analysis of Issues from the May 7, 2008, ASC Appendix 1 Filing</u>

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Cost and Contract System Load filed on May 7, 2008 by Idaho Power, and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base – No changes made except to the functionalization of cash working capital due to functionalization changes made subsequent to the May 7, 2008, filing.

SCHEDULE 1A: Cash Working Capital – No changes made except to the functionalization of cash working capital due to functionalization changes made subsequent to the May 7, 2008, filing.

SCHEDULE 2: Capital Structure and Rate of Return – No changes made except for carryover of Schedule 1 change discussed above.

SCHEDULE 3: Expenses- No changes except for a change to the functionalization of account number 935, Maintenance of General Plant, made subsequent to the May 7, 2008, filing.

SCHEDULE 3A: Taxes – Small change resulting from imposing a rounding convention to the interest rate calculations made subsequent to the May 7, 2008, filing.

SCHEDULE 3B: Other Included Items – Account 411.6, Gain from Disposition of Utility Plant, is functionalized to Production consistent with a functionalization change made subsequent to the May 7, 2008, filing.

SCHEDULE 4: Average System Cost

1. **Distribution Loss:**

Statement of Issue: In its filing, Idaho Power Company used a 5 percent Distribution Loss Factor to determine its ASC.

a. Statement of Facts: The May 7, 2008, Appendix 1 template did not require a Utility to complete a Distribution Loss Study to determine its Contract System Load. As outlined in the ASCM ROD, BPA allows a participating Utility that has the ability to directly measure distribution losses on its system to submit such measurements, subject to BPA review and approval, with its ASC filing. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years.

   Utilities that do not have the ability to directly measure distribution losses on their system, and that do not submit with the Appendix 1 a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing, will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

b. Analysis of Position and Decision: For purposes of this expedited filing, BPA completed the Distribution Loss Factor outlined in the ASCM ROD, Section 4.10.5. Idaho Power's Distribution Loss Factor is determined to be 7.78 percent.

2. **Contract System Load: New Large Single Load (NLSL)**

   a. Statement of Issue: The Appendix 1 filing instructions for the May 7, 2008, submittal did not require information on possible NLSLs. BPA subsequently required that such data be included in the determination of a Utility's ASC.

   b. Statement of Facts: Idaho Power submitted annual data identifying one potential NLSL ("Customer 1") whose power needs increased from 34 aMW in 1995 to 46 aMW in 1996. Idaho Power subsequently provided monthly data that confirmed an increase of greater than 10 aMW over 12 consecutive months during such years.

   c. Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit the costs to serve an NLSL to be included in the calculation of a Utility's ASC. Customer 1 load in 2006 of 78 aMW is determined to be 44 aMW of NLSL, with the "grandfathered" 1995 load of 34 aMW excluded from NLSL status. BPA determined Idaho Power's 2006 NLSL Cost to be $68.65 per megawatt-hour. BPA determined the cost of serving the potential NLSL based on the fully allocated cost of all post-September 1, 1979, resources, major resource additions and long-term power purchases (5 years or longer contracts) used to determine Exchange Period ASCs as outlined in the ASCM ROD, section 4.5. Schedule 4 shows a Contract System Cost reduction of $26,461,649, reflecting the product of 44 aMW and $68.65/MWh, and a Contract System Load reduction of 385,440 MWh.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – No changes made.

SUPPORTING DOCUMENTATION: Salaries and Wages – No changes made.

SUPPORTING DOCUMENTATION: Ratios

1. **Maintenance of General Plant (GPM) Ratio:** Miscellaneous Equipment

   a. Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

   b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

c. Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

B. Identification and Analysis of Issues Based on Comments on the July 8, 2008, Draft ASC Report

No comments were submitted.

C. Identification and Analysis of Issues Based on comments on the August 4, 2008, Revised Draft ASC Report

SCHEDULE 1: Plant Investment/Rate Base–

1. For **Account** 108, line item "**Capital Leases - Common Plant"** and **In-Service: Depreciation of Common Plant**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

   b. Analysis of Position and Decision: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments"**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments"** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments (Electric))**, Account 114, line 92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4, 2008, report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4, 2008, report

SCHEDULE 3: Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)"**

    a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)"** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/Rate Base* (Acquisition Adjustments (Electric))**, (cell E92 in electronic template).

    b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

    a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses.

    b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4, 2008, report

SCHEDULE 3B: Other Included – no changes from the August 4, 2008, report

SCHEDULE 4: Average System Cost - – no changes from the August 4, 2008, report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

   a. Statement of Issue: For Labor Ratio Input line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

   b. Analysis of Position and Decision: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908. All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

D. Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC may be made for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a Utility's retail load during the BPA rate period. The change to an established ASC must be "material," i.e., result in a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more. BPA determined a change in Idaho Power's ASC using the methods as described in the ASCM ROD, section 4.2.10.

Table 1 below identifies the New Resource Addition information provided by Idaho Power for FY 2008 only (year ending December 2007).

Table 1: ASC New Resource Addition

	FY 2006	FY 2007	FY 2008	FY 2009
Production Rate Base			64,771,248	
Plant Material and Supplies Rate Base				
Fuel Stock Rate Base			7,916,038	
Production O&M Expense				
Production Depreciation Expense			1,813,550	
Power Purchases Expense				
Property Insurance			130,229	

Transmission Rate Base				
Transmission Depreciation Rate Base				
Transmission O&M Expense				
Transmission Contracts Expense				
Transmission Property Tax Expense				

(Expected) Annual Generation (MWh)			59,568	

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining Idaho Power's forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and Idaho Power's ASCs published in the July 8, 2008, report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and Idaho Power's ASCs as a result of Idaho Power's comments to the July 8, 2008, report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and Idaho Power's ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	467,386136	478,991,400	492,183,198	500,999,123	513,889,955
Transmission	92,347,749	91,705,109	91,091,667	90,418,765	89,787,296
NLSL Fully Allocated Cost ($/MWh)	74.12	72.28	71.09	70.74	70.36
(Less) NLSL Costs	28,566,965	27,859,851	27,400,275	27,264,525	27,119,667
Total Contract System Cost	**531,166,920**	**542,836,657**	**555,874,590**	**564,153,366**	**576,557,584**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	14,990,809	15,256,830	15,481,163	15,593,539	15,755,103
(Less) NLSL	385,440	385,440	385,440	385,440	385,440
Total Retail Load (Net or NLSL)	14,605,369	14,871,390	15,095,723	15,208,099	15,369,663
Distribution Loss	1,166,538	1,187,238	1,204,695	1,213,440	1,226,012
Total Contract System Load	**15,771,907**	**16,058,628**	**16,300,418**	**16,421,539**	**16595675**

AVERAGE SYSTEM COST

ASC ($/MWh)	**33.68**	**33.80**	**34.10**	**34.35**	**34.74**

Revised Table 2: FY 2009-2013 ASC Summary – August 4, 2008

Date (mid-year)	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	466,891,079	477,582,472	492,592,137	501,415,361	514,475,248
Transmission	92,347,749	91,705,109	91,091,667	90,418,765	89,787,296
NLSL Fully Allocated Cost ($/MWh)	79.04	75.94	75.80	75.39	75.01
(Less) NLSL Costs	30,463,453	29,269,076	29,216,049	29,058,258	28,910,883
Total Contract System Cost	**531,166,920**	**542,836,657**	**555,874,590**	**564,153,366**	**576,557,584**

CONTRCT SYSTEM LOAD

Total Retail Load @ Meter	14,990,809	15,256,830	15,481,163	15,593,539	15,755,103
(Less) NLSL	385,440	385,440	385,440	385,440	385,440
Total Retail Load (Net or NLSL)	14,605,369	14,871,390	15,095,723	15,208,099	15,369,663
Distribution Loss	1,166,538	1,187,238	1,204,695	1,213,440	1,226,012
Total Contract System Load	**15,771,907**	**16,058,628**	**16,300,418**	**16,421,539**	**16595675**

AVERAGE SYSTEM COST

ASC ($/MWh)	**33.53**	**33.63**	**34.02**	**34.27**	**34.67**

Final Table 2: FY 2009-2013 ASC Summary – September 11,2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	470,949,913	481,694,355	496,739,225	505,581,825	518,655,158
Transmission	93,579,418	92,933,257	92,316,991	91,643,186	91,009,961
NLSL Fully Allocated Cost ($/MWh)	79.11	76.01	75.87	75.46	75.08
(Less) NLSL Costs	30,492,835	29,297,863	29,244,354	29,086,338	28,938,635
Total Contract System Cost	**534,036,495**	**545,329,749**	**559,811,862**	**568,138,673**	**580,726,484**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	14,990,809	15,256,830	15,481,163	15,593,539	15,755,103
(Less) NLSL	385,440	385,440	385,440	385,440	385,440
Total Retail Load (Net or NLSL)	14,605,369	14,871,390	15,095,723	15,208,099	15,369,663
Distribution Loss	1,166,538	1,187,238	1,204,695	1,213,440	1,226,012
Total Contract System Load	**15,771,907**	**16,058,628**	**16,300,418**	**16,421,539**	**16,595,675**

AVERAGE SYSTEM COST

ASC ($/MWh)	**33.86**	**33.96**	**34.34**	**34.60**	**34.99**

VI. BPA STATEMENT

This Final ASC determination reflects an increase in the cost to serve Idaho Power's NLSL. ASCs for years 2009 through 2013 shown in Final Table 2 above are increased to reflect such change.

This ASC determination is BPA's best estimate of Idaho Power's FY 2009 ASC based on the information and data provided from Idaho Power during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination for FY 2009. This determination is made solely for the purpose of providing estimated FY 2009 ASCs for use in the development of BPA's FY 2009 power rates in BPA's WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such reviews will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance with the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System of Idaho Power for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The Final Appendix 1 Filing, Forecast Model and NLSL assessment used to calculate Idaho Power's ASCs can be viewed at BPA's ASC website:
http://www.bpa.gov/corporate/finance/ascm/filings.cfm.